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INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Project Minerva

Contents

1.0 Facility Information

Facility name:	Project Minerva Wells 1-4
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Well location:	[redacted]

Gulf Coast Sequestration (GCS) will conduct injection well plugging and abandonment according to the procedures below.

2.0 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

60-day notice will be provided prior to plugging operations. Adjustments to the plugging plan will be incorporated to meet the Director's guidance.

It is unlikely that a homogenous liquid will exist from the surface wellhead gauge down to the perforations. The homogenous liquid is required to accurately determine the downhole pressure at the perforations; a mixture of gas and super-critical phase CO_2 are not conducive to making accurate pressure calculations. Consequently, a wireline unit will deploy a tubing downhole pressure gauge with either surface read-out or recorded memory data, and the pressure at the perforations will be measured directly.

After determining the downhole pressure at perforations, the equivalent density of fluid to balance, this pressure will be calculated using the equation: Density = Pressure ÷ .052 ÷ TVD, where density is in pounds-per-gallon, pressure is psi, and TVD is feet.

A work fluid with the density calculated as above from the downhole pressure will be mixed from a freshwater base, with bentonite added for viscosity and barite added for weight. This fluid is robust at the expected temperatures and is compatible with common cement spacers and cements.

A work string likely consisting of 2-7/8" tubing will be run into the well using a workover rig. If the well has an existing tubing string with packer, the workover rig will make up a work joint to the existing tubing, pull tension to unseat the tubing hanger from the wellhead, and pull further tension to unseat the packer; if the packer has to be removed by milling, this can also be done with the work string. With the tubing work string in the hole or the existing tubing/packer unseated, the work fluid will be slowly pumped down the tubing towards the perforations. If fluid returns do not arrive back at surface, it may be necessary to add LCM (lost circulation material) to the work fluid to plug the formation porosity at the perforations until fluid returns do arrive at surface.

Pumping rate will be low so that undue friction pressures are not exerted on the formation open at the perforations; the volume to be pumped will be on the order of 700 bbls.

3.0 Planned External Mechanical Integrity Test(s)

GCS will conduct at least one of the tests listed in Table 3.1 to verify external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

3.1 Procedures that will be followed for each type of test

At the end of injection activities, the (internal test) pressure test can be performed with the tubing in-place, still connected to the packer. The pressure inside the 9-5/8" long string casing can be increased to a value above the standard pressure applied during injection. The other tests require that the tubing be pulled out of the way. The logs will be run inside the long string.

3.2 Gauges and/or other equipment

Injection of CO_2 is expected to occur at a surface pressure of 1950 psi, and the tubing/casing annular pressure is expected to be 100 psi greater, or 2050 psi. These pressures can easily be read on 0 – 3000 psi or 0 – 5000 psi gauges. The pressure test (3rd listed on table, below) could be 2200 psi, again measured with 3000 psi or 5000 psi rated gauges.

3.3 What constitutes a "pass" or "fail" for each test?

Cement bond log(s): significant (negative) deviation of the cement quality from the first cement bond logs run during well construction will provide an alert about this important external barrier between injection and underground sources of drinking water (USDW), but it is not necessarily a "fail". "Fail" will present itself if the subsequent acoustic log reveals moving fluids in the cemented space. "Pass" will be the result if the acoustic log does not detect fluid movement.

The pressure test and optional casing caliper log will "fail" the long string if pressure does not hold at the applied test value, or if the caliper log reveals substantial corrosion/erosion which has decreased the wall thickness enough to likely result in a hole. "Pass" will be the opposite, a pressure test that holds steady, and a caliper log which does not reveal a condemning loss of wall thickness.

Test Description	Location
Cement Bond Log(s) (external MIT)	Run CBL & Ultrasonic logs from permanent packer to surface; these will repeat the logs run when casing was first cemented prior to injection activities. Discrepancies, if any, can be noted between the logs as an indication of cement quality improvement (due to carbon hydroxide hardening of the cement) or degradation (due to casing movement or other cement sheath disturbance).
Acoustic Log (external MIT)	Run acoustic log post-injection to register any fluid movements external to the long string casing; log from permanent packer to surface.
Pressure test (internal MIT)	Place tubing plug in profile nipple below permanent packer; pressure test long string casing from tubing plug to surface, using packer fluid. Test pressure to be greater than annulus pressure maintained during injection activities.
(Optional) Casing caliper log (internal MIT)	Casing caliper log optional if long string casing successfully passes the pressure test (above). Caliper log will provide information about long string casing wall thickness loss due to corrosion or erosion; information useful for future projects. Log from permanent packer to surface.

Table 3.1 Planned MITs

4.0 Information on Plugs

GCS will use the materials and methods noted in Table 5.1 to plug the injection well. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted to the UIC Program Director with the well plugging plan. GCS will report the wet density and will retain duplicate samples of the cement used for each plug.

5.0 Methods used for volume calculations

During well construction, the 9-5/8" long string casing will be spot-calipered to confirm that the i.d. equals that of new pipe, 8.535". After running casing and cementing, a casing caliper log will be run as a baseline against which to measure future corrosive and/or erosive loss of wall thickness. Prior to plugging, casing i.d. data will be evaluated and compared to original baseline data. Calculations to determine cement plug and displacement volumes will use the final casing i.d. values. An example of the possible sensitivity of one-half casing wall thickness loss:

Original Capacity = $\frac{8.535^2 \text{ in}^2}{1029.4}$ = 0.0708 bbls per foot. 1000 ft of casing holds 70.8 bbls.
Original wall thickness 0.535".

Final Capacity = $\frac{9.079^2 \text{ in}^2}{1029.4}$ = 0.0801 bbls per foot. 1000 ft of casing holds 80.1 bbls.
Final wall thickness 0.273".

Volume calculations will be based upon the final dimensions of the long string casing.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of boring in which plug will be placed (in.)	8.535	8.535	8.535	8.535	8.535	8.535	8.535
Depth to bottom of tubing or [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sacks of cement to be used (each plug)	160	160	160	160	160	200	200
Slurry volume to be pumped (ft^3)	208	208	208	208	208	260	260
Slurry weight (lb./gal)	16.2	16.2	16.2	16.2	16.2	16.2	16.2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Type of cement or other material	50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant	50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant	50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant	50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant	50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant	50:50 Class H: Pozzolan (fly ash) +accelerator + bonding agent + dispersant + defoamer	50:50 Class H: Pozzolan (fly ash) +accelerator + bonding agent + dispersant + defoamer
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balance method	Balance method	Balance method	Balance method	Balance method	Balance method	Balance method

Table 5.1 Plugging details

6.0 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), GCS will notify the UIC Program Director at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

7.0 Plugging Procedures

Plug-and-abandonment (P&A) cementing operations should occur when fluids in the wellbore are at balance with the exposed formation (in this case, via perforations in the long string). Water is the major component of the work fluid and is the liquid component of the cement, and water is effectively incompressible. A barrel of water introduced into a closed system will cause one barrel of water to be displaced out of the system.

All of the P&A plugs listed in Table 5.1 and planned for this well are to be placed by the Balance Method; the cement in fluid form will be precisely placed by accurately measuring the volumes of spacer, cement, and work fluid so that the cement height outside the work string will match the height inside the work string. As soon as the cement is in place, the work string will be slowly pulled from the still-fluid cement mixture, leaving a cement column of a known height.

The density difference between the work fluid and fluid cement will not cause disruption to the placement of cement, because the major component of water is incompressible, a barrel in leads to a barrel out. It is simply measurement of lengths, diameters, and volumes followed by math.

An example of the first P&A plug will be shown below. The dimensions are for the 9-5/8" long string with 8.535" i.d. Assumes zero wall thickness loss; see earlier explanation how this value will be updated as needed. The work string is intended to be a very-commonly used 2-7/8" 7.90 lb/ft tubing found on most workover rigs.

Salt can be an accelerator to the hydration process of cement, and it is possible that the work fluid might contain salt if it is made from the packer fluid used during the injection activities. To prevent cement from coming into contact with any salt in the work fluid, a fluid spacer containing no salt is pumped ("in the space") between cement and the work fluid. The standard cement plug placement thus consists of pumping accurate amounts of each of these three (3) fluids: spacer, cement, work fluid.

Notes about plug placement:

- Tubing work string joints are typically 30' long; the safest manner in which to pump fluids down the work string is to have the top of the top joint be located 3' – 4' above the rig floor, so that the cementing head and hoses can be easily connected by 5' – 6' tall personnel. The desired setting depth of a cement plug (e.g. 10,970' for the example used here) is rarely equally divided by 30', so the real-world depth will be whatever the tubing work string measures, minus the 3' – 4' above the rig floor, as close as it can get with full numbers of joints.
- Calculations to determine cement volume are performed first in barrels, then converted to ft^3, and finally ordered as no. of sacks from the cement supplier. In practice, a calculation resulting in 152 sacks of cement required will normally be rounded-up to the next-highest unit of ten (10), in this case, 160 sacks. There is always some cement lost during delivery to location, and also some cement lost during mixing, so the volume tends to be rounded-up.
- The desired top of cement (T.O.C.) may be, for example, 500' above the bottom of cement. By rounding-up the cement volume number, the calculated TOC may be higher than the perfect scenario of 500'. In reality, the spacer and cement are traveling face-to-face inside a tube for more than two (2) miles, and there will be some mixing. The interface between the spacer and cement normally leads to a certain amount of contaminated cement, which does not attain the desired properties of compressive strength/hardness. For deep-set cement plugs, it is very common to find the top 2 – 3 bbls of cement contaminated, even after WOC for a lengthy period of time. This contaminated cement can be circulated out of the wellbore prior to setting the next cement plug; it will be a viscous fluid. While performing this circulation, the work string tubing can be used to "tag" (i.e. land upon, touch) the hardened part of the cement plug.

Following are the calculation results for placement of the bottom P&A cement plug for the subject well.

[redacted]

Figure 7.1 Cement plug calculations

The desired cement plug setting depth is [redacted] As described earlier, the tubing work string may-or-may-not reach exactly [redacted], and the top of cement at [redacted] (see calculated cell above) will likely contain some contaminated cement at the top. By the time the next cement plug is placed, it is likely that the first plug's contaminated top will be circulated-out and be very close to the desired [redacted].

After displacing the cement plug to the balanced depth, the tubing work string will be slowly pulled to a point at least 500 ft above the top of cement, and the tubing work string will be circulated (the long way, down the tubing and up the annulus) to clear any excess cement out of the well; reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement (W.O.C.) for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended. After W.O.C. 24 hours (or such time recommended by cementing contractor for plug to achieve 100 Bc or 1000 psi compressive strength), run tubing work string slowly into well to tag the top of cement. Circulate through the work string during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when it encounters cement, and to begin to move contaminated, viscous cement up and out of the wellbore. Tagging the hardened cement top will determine the precise location of the cement compared to desired placement; set down 10,000 lbs of work string weight on top of the cement plug to prove its competency. The cross-sectional area of 2-7/8" tubing is approximately 2.7 in^2, and the force exerted on the cement top would be approximately 10,000 lbs $\div$ 2.7 $in^2 \approx$ 3700 psi.

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing work string and circulate through it to clear any cement from the open end and to circulate any contaminated cement out of the wellbore. Mix and pump via the balanced method another 500-ft cement plug similar to the first plug, placing it on top of the first plug. Repeat the process of pulling at least 500 ft above the calculated top of cement, circulating out any excess cement, W.O.C. while periodically circulating and tagging the top of second plug and proving its competency.

As a conservative approach, each of the plugs will be tagged using the method described. Tagging each plug will prove its location and competency, thus removing doubt about the suitability of the plugging process. It will be a time-consuming process due to the W.O.C. intervals, but successfully placed cement plugs will protect USDW.

8.0 <u>Contingency procedures/measures</u>

Discussed above in the bulleted points concerning real-world implications of tubing lengths, cement volumes, and spacer/cement interface contamination.